THE FUTURE OF THE HYDROGEN ECONOMY: BRIGHT OR BLEAK?

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Abstract

In the past, many have considered the production and use of hydrogen, assuming that it is just another gaseous fuel and can be handled much like natural gas in today's energy economy. With this study we present an analysis of the energy required to operate an elemental hydrogen economy, with particular reference to road transport. High-grade electricity from renewable or nuclear sources is needed not only to generate hydrogen, but also for all the other essential stages. However, because of the molecular structure of hydrogen, the infrastructure is much more energy-intensive than in an oil and natural gas economy. In a „Hydrogen Economy" the hydrogen, like any other commercial product, is subject to several stages between production and use. Hydrogen has to be packaged by compression or liquefaction, transported by surface vehicles or pipelines, stored, and transferred to the end user. Whether generated by electrolysis or by chemistry, and even if produced locally at filling stations, the gaseous or liquid hydrogen has to undergo these market processes before it can be used by the customer. Hydrogen can also be derived chemically at relatively low cost from natural gas or other hydrocarbons. However, as there are no energetic or environmental advantages, we do not consider this option. In this study, the energy consumed by each stage is related to the true energy content - the higher heating value (HHV) - of the delivered hydrogen. The analysis reveals that much more energy is needed to operate a hydrogen economy than is required for fossil energy supply and distribution today. In fact, the input of electrical energy to make, package, transport, store and transfer hydrogen may easily exceed the hydrogen energy delivered to the end user - implying an well-totank efficiency of less than 50 per cent. However, precious energy can be saved by packaging hydrogen chemically in a synthetic liquid hydrocarbon like methanol or ethanol. To de-couple energy use from global warming, the use of "geocarbons" from fossil sources should be avoided. However, carbon atoms from biomass, organic waste materials or recycled carbon dioxide could become the carriers for hydrogen atoms. Furthermore, energy intensive electrolysis may be partially replaced by the less energy intensive chemical transformation of water and carbon to natural and synthetic hydrocarbons, including bio-methanol and bio-ethanol. Hence, the closed natural hydrogen (water) cycle and the closed natural carbon (CO2) cycle may be used to produce synthetic hydrocarbons for a post-fossil fuel energy economy. As long as the carbon comes from the biosphere ("bio-carbon"), the synthetic hydrocarbon economy would be far better than the elemental hydrogen economy - both energetically and environmentally.

***Key words**: alternative fuels, hydrogen, hydrogen economy*

1. Introduction

Hydrogen has fascinated generations of people for centuries, including visionaries like Jules Verne. A "Hydrogen Economy" is often advocated as the ultimate solution for energy and environment. Hydrogen societies have been formed for the promotion of this goal by publications, meetings and exhibitions.

Hydrogen can be produced from electricity and water. Its conversion to heat or power is simple and clean. When burnt with oxygen, hydrogen generates no pollutants, but only water, which can return to nature. However, hydrogen, the most common chemical element on the planet, does not exist in nature in its elemental form. It has to be separated from chemical

compounds, by electrolysis from water or by chemical processes from hydrocarbons or other hydrogen carriers. The electricity for the electrolysis may come eventually from clean renewable sources such as solar radiation, kinetic energy of wind and water or geothermal heat. Therefore, hydrogen may become an important link between renewable physical energy and chemical energy carriers.

But have the physics and chemistry been properly considered? Most attention has been given to the apparent benefits of hydrogen in use, while the upstream aspects of a hydrogen economy are rarely addressed, Figure 1.

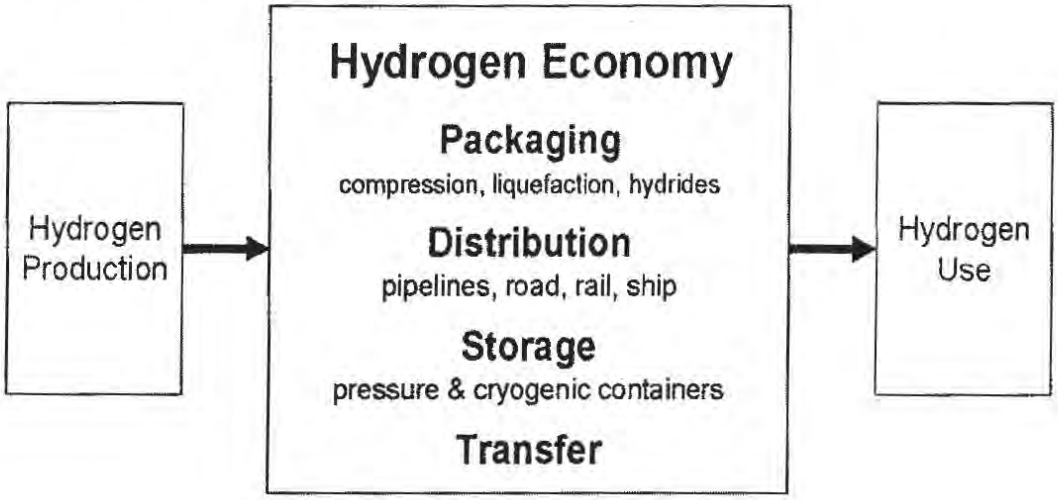

Figure 1. Schematic Representation of an elemental "Hydrogen Economy"

Like any other product, hydrogen must be packaged, transported, stored and transferred, to bring it from production to final use. These standard product processes require energy. In today's fossil energy economy, the energy lost between the well and the consumer is about 12% for oil and about 5% for gas. The present paper gives estimates of the upstream energy required to operate a „Hydrogen Economy". Our analysis should be of particular interest for the assessment of fuel options for transport applications.

Without question, technology for a hydrogen economy exists or can be developed. in fact, considerable amounts of hydrogen are generated, handled, transported and used in the chemical industry today. However, this hydrogen is a chemical substance, not an energy commodity. Hydrogen production and transportation costs are absorbed in the price of the synthesized chemicals. The cost of hydrogen is irrelevant as long as the final products find markets. Today, the use of hydrogen is governed by economic arguments and not by energetic considerations.

However, if hydrogen is to be used as an energy carrier, energetic issues must also be considered. How much high-grade energy is required to make, to package, to handle, to store and to transport hydrogen? It would be difficult to establish a sustainable energy future if much of the energy harvested from nature is wasted before it reaches the energy consumer. We have examined the key stages by physical and chemical reasoning and conclude that the future energy economy is unlikely to be based on elemental hydrogen. Hydrogen may be the main link between renewable physical and chemical energy, but most likely it will reach the consumer chemically packaged in the form of one or more consumer-friendly natural or synthetic liquid hydrocarbons.

Preliminary results of our study have already been presented at THE FUEL CELL WORLD conference in July 2002 [1].

2. Properties of Hydrogen

The physical properties of hydrogen are well known [2, 3]. It is the smallest of all atoms. Consequently, hydrogen is the lightest gas, about eight times lighter than methane (representing natural gas). Promoters praise the energy content of hydrogen. However, for most practical applications, the heating value per unit mass of any gaseous energy carrier is of little relevance [4]. Most storage tanks are limited by volume, especially in automotive applications. Also, the capacity of pipelines depends on the square of their diameter, and the flow velocity. Therefore, in most cases, it is more meaningful to consider the energy content per unit volume.

For this energy analysis, it is proper to use the heat of formation or higher heating value (HHV), which is the true energy content of the fuel, based on the energy conservation principle (i.e. the 1st Law of Thermodynamics). Unfortunately, in many countries, when expressing the efficiency of heat engines and other energy converters, the lower heating value (LHV) is used. However, when referred to the physically correct HHV, the efficiencies would be lowered according to the ratio of LHV to HHV, i.e. by factor 0.940 for gasoline, 0.903 for natural gas and 0.845 for hydrogen [5]. Hence, efficiencies and fuel economies on the LHV basis are 6.4%, 10.7% and 18.3% higher than those on the HHV basis. In particular, hydrogen energy converters look much less attractive if their output is related to the physically correct energy input. Also, LHV-efficiencies may exceed 100% - as with some condensing boilers - which violates the energy conservation principle.

Therefore the use of the LHV should be abandoned for all energy engineering applications.

Since the production of hydrogen is governed by the heat of formation or the higher heating value, its use should also be related to the HHV energy content. Our analysis is based on physical and chemical reasoning and therefore uses the higher heating value (HHV) throughout. The reference density and heating values of hydrogen and methane used in this study are shown in Table 1.

Table 1. Density and heating values of hydrogen and methane

	Units	Hydrogen	Methane
Density at NTP	kg/m3	0.0887	0.707
Gravimetric HHV	MJ/kg	142.0	55.6
Volumetric HHV at NTP	MJ/m3	12.7	40.0

The higher heating values "HHV" per unit volume of various energy carrier options are shown in Fig. 2.

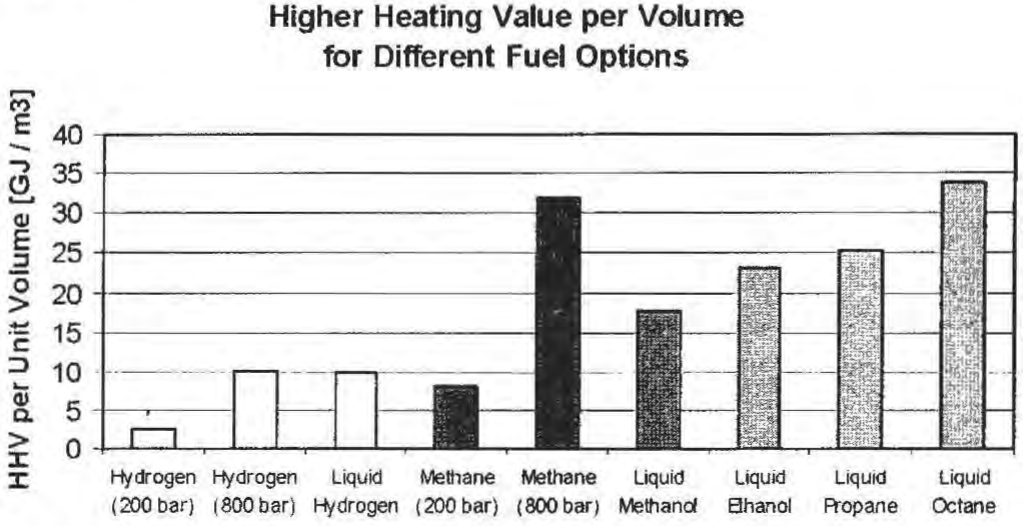

Figure 2. Volumetric HHV energy density of different fuels

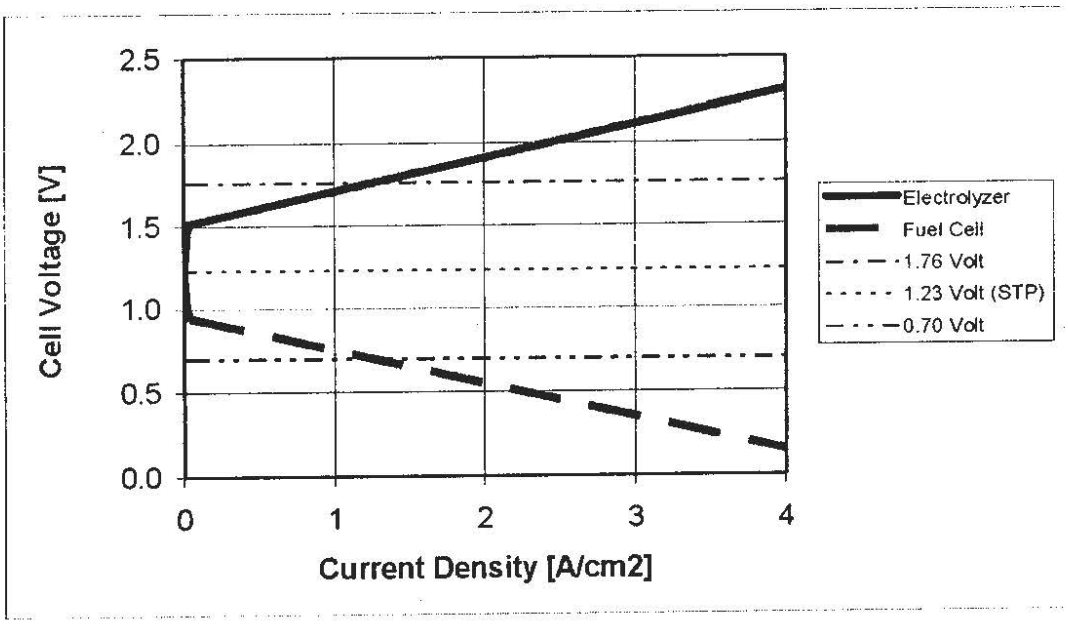

Figure 3. Voltage-current characteristics of hydrogen electrolyzer and fuel cell

Under open circuit conditions, the standard electrochemical potential of the hydrogen-oxygen pair is 1.23 Volts at NTP. To optimize the system efficiency, fuel cells are normally operated at about 0.7 Volt – i.e. at about 1.2 A/cm^2. We assume the same optimization requirements also hold for an electrolyzer. In this case, the corresponding voltage of operation is 1.76 Volts - as indicated by the horizontal dash-dot line in Figure 3. The standard potential of 1.23 Volts corresponds to the higher heating value HHV of hydrogen. Consequently, the over-voltage is a measure of the electrical losses of the functioning electrolyzer. The losses relative to the HHV of hydrogen depend on the hydrogen production rate – i.e. the current density, as shown in Figure 4.

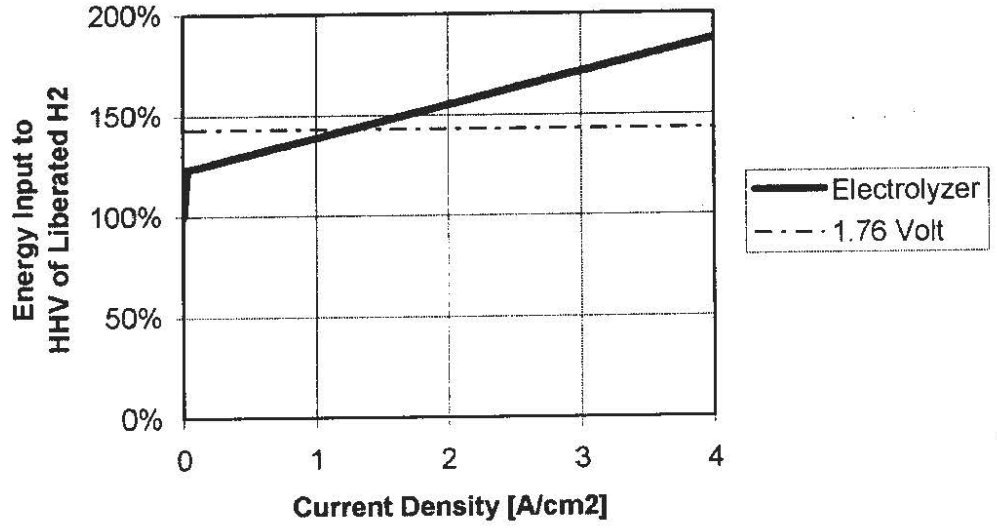

Figure 4. Energy input to electrolyze water compared to HHV energy of liberated hydrogen

Compared with the standard potential of 1.23 Volts, an operating potential of 1.76 Volts implies that 1.43 energy units must be supplied to generate 1 HHV unit of hydrogen, giving a stage efficiency of 1/1.43 = 70%. At higher specific hydrogen production rates, i.e. higher current densities, this efficiency is even lower. Also, this analysis takes no account of the

losses in converting the high voltage AC electricity from the grid to the high current DC electricity used in electrolyzers.

Nevertheless, electrolysis may be the only practical link between physical renewable energy (kinetic energy from wind, water and waves, radiation from the sun, geothermal heat) and non-stationary fuel cells needed for transportation. Also, electrolytic production of hydrogen offers one method of storing electricity from intermittent sources. Other - and proven – methods include hydro-electricity, pumped storage, flywheels and batteries.

4. 2. Reforming

Hydrogen can also be extracted from hydrocarbons by reforming. This chemical process is, in principle, an energy transformation process. The HHV energy contained in the original substance can be transferred to the HHV energy of hydrogen. Theoretically, no external energy is needed to convert a hydrogen-rich energy carrier like methane (CH4) or methanol (CH3OH) into hydrogen by an autothermal reforming process.

However in reality, thermal losses cannot be avoided and the HHV energy contained in the generated hydrogen is always less than that in the original hydrocarbon fuel. The efficiency of hydrogen production by autothermal reforming is about 90%, but may be less, especially for compact, mobile plant. Thus at least
1.1 units of energy must be invested to obtain 1 HHV unit of hydrogen. Also, more CO2 is released by this indirect process than by direct use of the hydrocarbon precursors. Hence this reduces the overall well-to-wheel efficiency and increases the overall CO2 emissions.

For most practical applications, natural gas can do what hydrogen does. There is no need for a conversion of natural gas into hydrogen which, as shown in this study, is more difficult to package and distribute than the natural energy carrier. For all stationary applications, the source energy (electricity or hydrocarbons) could be used directly by the consumer at comparable end-use efficiency and hence higher overall source-to-service efficiency and lower overall CO2 emission. Therefore, transforming electricity or natural gas to hydrogen offers no universal solution to the energy future.

At today's energy prices, it is considerably more expensive to produce hydrogen by water electrolysis than by reforming of fossil fuels. According to [6], it costs around $5.60 for every GJ of hydrogen energy produced from natural gas, $10.30 per GJ from coal, and $20.10 per GJ to produce hydrogen by electrolysis of water. Before taxes, gasoline costs about $3.00 per GJ.

5. Packaging of Hydrogen

5. 1. Compression of Hydrogen

Compressing gas requires energy, and the compression work depends on the thermodynamic compression process. Ideal isothermal compression, which is impossible in practice, follows a simple equation:

$$W = p_0 V_0 \ln(p_1/p_0).$$

For ideal gases, and real gases far above their boiling temperature, the actual thermodynamic process is more closely described by the adiabatic compression equation [7]:

$$W = [\gamma/(\gamma - 1)]\, p_0 V_0 [(p_1/p_0)^{(\gamma - 1)/\gamma} - 1] \qquad (1)$$

where:

W	[J/kg]	specific compression work,
p_0	[Pa]	initial pressure,
p_1	[Pa]	final pressure,

V_0	[m^3/kg]	initial specific volume,
γ	[-]	ratio of specific heats, adiabatic coefficient,

In both isothermal and adiabatic compression, the compression work is the difference between the final and the initial energy states of the gas. The difference between the two compression processes is shown by the final temperature of the compressed medium. In the ideal isothermal case, the temperature would remain constant, while under adiabatic conditions, it rises considerably. Moreover, the magnitude of the compression work depends on the nature of the gas.

For example, for hydrogen and methane, the adiabatic coefficients and initial specific volumes are:

$H_2\ \gamma = 1.41\ V_0 = 11.11\ m^3/kg,$

$CH_4\ \gamma = 1.31\ V_0 = 1.39\ m^3/kg.$

For adiabatic compression of diatomic hydrogen and five-atomic methane from atmospheric conditions to higher pressures, the energy consumed is shown in Figure 5. Clearly, much more energy per kg is required to compress hydrogen than methane.

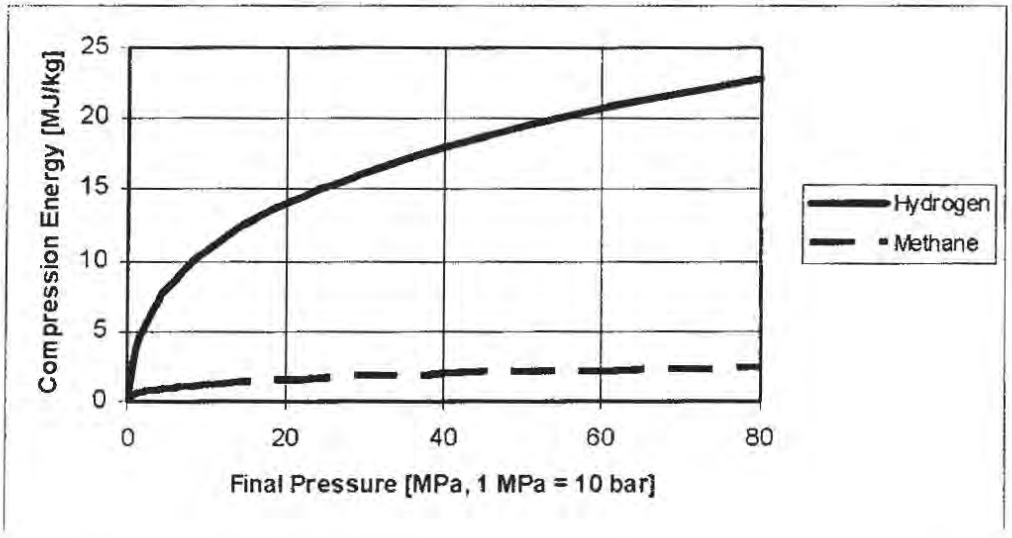

Figure 5. Adiabatic compression work versus final pressure for hydrogen and methane

Multi-stage compressors with intercoolers operate somewhere between the two limiting cases of isothermal and adiabatic compression. Also, compared with methane, hydrogen passes compression heat to the cooler walls more readily, which makes the process more nearly isothermal. Data provided by a leading manufacturer of hydrogen compressors [8] show that the energy required for a 5stage compression of 1,000 kg of hydrogen per hour from ambient pressure to 20 MPa is about 7.2% of its HHV. Adiabatic, isothermal, and an actual multi-stage compression of hydrogen are compared in Figure 6.

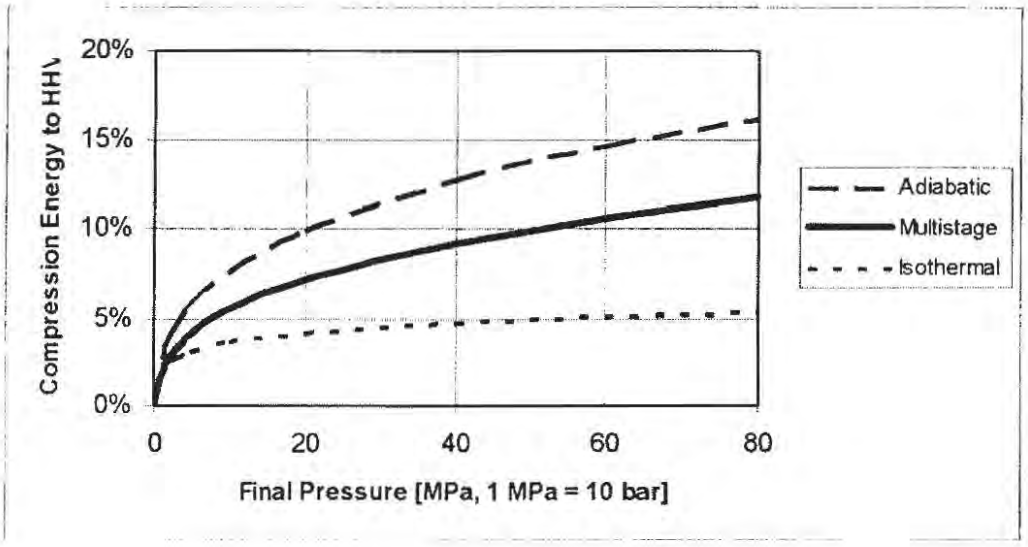

Figure 6. Energy required for the compression of hydrogen compared to its higher heating value

For a final pressure of 20 MPa, the actual energy requirements for multi-stage compression would amount to about 8% of the HHV energy content of hydrogen. However, this analysis does not include any losses in the electrical power supply system. At least 1.08 units of energy must be invested in compression to obtain 1 unit of hydrogen HHV at 20 MPa. The number becomes 1.12 for compression to 80 MPa if the proposed vehicle tank pressure standard of 70 MPa is adapted by the automobile industry.

With 5% mechanical and 5% electrical losses, the total electricity input may be 20%. If the electricity is generated in a coal-fired thermal power plant, the corresponding total primary energy consumption could reach as much as 80% of the HHV of the compressed hydrogen, giving a source-to-service efficiency of as little as 55%.

5. 2. Liquefaction of Hydrogen

Even more energy is needed to compact hydrogen by liquefaction. Theoretically, only about 14.2 MJ/kg_{LH2} have to be removed to cool hydrogen gas from 298 K (25°C) to 20.3 K and to condense the gas at 20.3 K and atmospheric pressure [9]. This exergy analysis includes the energy needed for the removal of heat released by the para-ortho conversion of electron spin orientations at low temperatures. In the interests of energy efficiency, hydrogen is liquefied by complex processes. The cooling is accomplished by multi-stage compression and expansion coupled with counter-flow heat exchange and energy recovery by expansion turbines. Generally, a three-stage vapor compression propane refrigeration system is used for cooling from ambient temperature to 73K, followed by multi-stage nitrogen expansion to obtain 77K, and a multi-stage helium compression-expansion to obtain the liquefaction of hydrogen at 20.3K and atmospheric pressure [10]. However, the 14.2 MJ/kg_{LH2} obtained by an exergetic analysis does not include any electrical, mechanical, thermal, or flow-related losses. Therefore, we present published operating data of representative hydrogen liquefaction plants.

The medium size liquefaction plant of Linde Gas AG at Ingolstadt in Germany produces 182 kg_{LH2}/hour [11] at a specific energy consumption of about 54 MJ/kg_{LH2} [9], while the best large plants in the US require 36 MJ/kg_{LH2} to liquefy hydrogen [9]. The authors of a Japanese feasibility study of a hydrogen liquefaction plant of 300 metric tons LH_2 per day or 12,500 kg_{LH2}/h capacity conclude that in the best case at least 105.2 MW are required to operate the plant [12]. This corresponds to 30.3 MJ/kg_{LH2} for a plant about 6 times larger than any

existing facility. The use a helium-neon mixture for the low temperature cycle has been suggested to reduce the energy consumption to, perhaps, 25.2 MJ/kg_{LH2} (= 7 kWh/kg_{LH2}) for a plant producing 7,200 kg_{LH2} per hour, or 173 metric tons LH2 per day [9], but experimental results are not yet available.

The variation of energy consumption with capacity for existing hydrogen liquefaction plants [13] is shown in Figure 7.

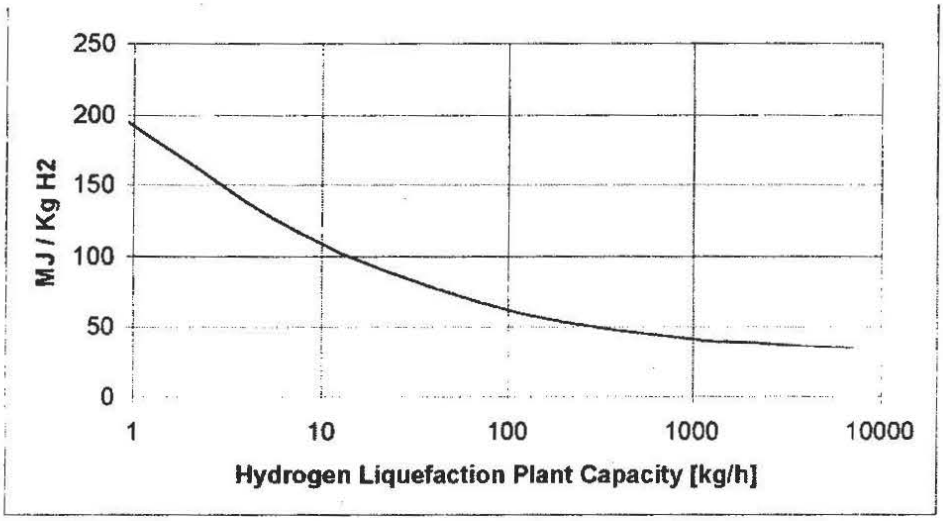

Figure 7. Typical energy requirements fo the liquefaction of hydrogen versus plant capacity

As expected, more electrical energy is consumed for the liquefaction of hydrogen in small plants than in large facilities. For existing plants of 10 and 1,000 kg_{LH2}/h capacity, at least 100 and 40 MJ/kg_{LH2} are required for liquefaction, respectively.

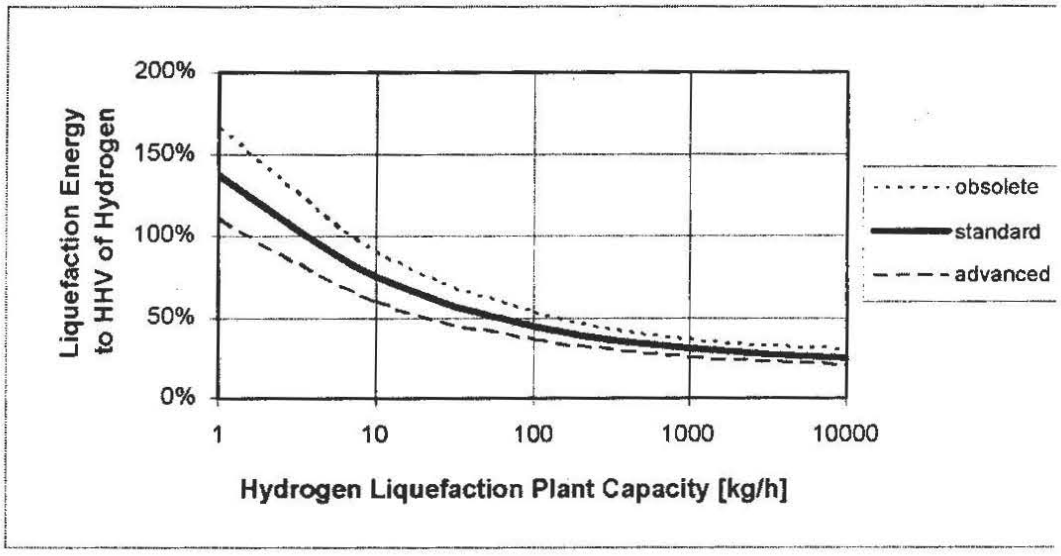

Figure 8. Liquefaction energy relative to the HHV of hydrogen versus plant capacity

The required energy input for liquefaction relative to the HHV of hydrogen is shown in Figure 8. For very small liquefaction plants (>5 kg_{LH2}/h), the energy needed to liquefy hydrogen may exceed the HHV energy. Even 10,000 kg_{LH2}/h plants (perhaps four times larger than any existing liquefaction facility) would consume about 25% of the HHV energy of the liquefied hydrogen. For the available technology, 40% would be a reasonable number. On other words, 1.4 units of energy would have to be supplied to the liquefier as hydrogen and

electricity to obtain 1 HHV unit of liquid hydrogen. However, no liquefaction plants of comparable performance have yet been built.

Moreover, liquid hydrogen storage systems lose some hydrogen gas by boil-off. This is due to unavoidable heat leakage, and must be permitted for safety reasons. The loss rate is dependent on the size of the store, but would be significant for those used in vehicles, and may amount to 3 to 4 per cent a day [16]. While this gas may be used when the vehicle is operated, it would have to be vented if the vehicle was parked. For example, if parked at an airport for 14 days, the loss of hydrogen could be 50 to 60 per cent.

5. 3. Physical Metal Hydrides

Hydrogen may be stored physically, e.g. by adsorption in spongy matrices of special alloys as physical metal hydrides. The hydrogen forms a very close, but not perfect, bond with alloys like $LaNi_5$ or $ZrCr_2$.

Rather than considering specific hydrides, the energy balance will be described in general terms. Again, energy is needed to produce and compress hydrogen. Some of this energy input is lost in form of waste heat. When a metal hydride storage container is filled with hydrogen, heat is released and usually lost. Conversely, when the process is reversed to liberate the stored hydrogen, heat must be added. The release of hydrogen at pressures below the filling pressure requires a heat inflow proportional to the hydrogen release rate. For small release rates and for containers designed for efficient heat exchange with the environment, no additional heat may be required. Also the hydrogen storage container may be heated with waste heat from the fuel cell. Thus the energy needed to package hydrogen in physical metal hydrides may be more or less limited to the energy needed to produce and compress hydrogen to a pressure of 3 MPa [15]. This is significantly less than for hydrogen stored as compressed gas at 20 MPa, and far less than for hydrogen stored at 80 MPa, or as a liquid.

However, according to [14], metal hydrides store only around 55-60 kg of hydrogen per m^3, whereas, ignoring the container, liquid hydrogen has a volumetric density of 70 kg/m^3. Moreover, metal hydride cartridges are very heavy. A small metal hydride container holding less than 2 g of hydrogen weighs 230 g [16]. Hence it might require a hydride store weighing up to 200 kg to contain 2 kg of hydrogen. Since this is equivalent to only about 8 liters or 2 U.S. gallons of gasoline, this type of hydrogen packaging is quite impractical for automotive applications.

5. 4. Chemical Metal Hydrides

Hydrogen may also be stored chemically in alkali metal hydrides. There are many options in the alkali group like LiH, NaH, KH, CaH2, but complex binary hydride compounds like LiBH4, NaBH4, KBH4, LiAlH4 or NaAlH4 have also been proposed for hydrogen storage [17]. None of these compounds can be found in nature. All have to be synthesized from pure metals and hydrogen.

Let us consider the case of calcium hydride CaH2. The compound is produced by combining pure calcium metal with pure hydrogen at 480°C. Energy is needed to extract calcium from calcium carbonate (limestone) and hydrogen from water by electrolysis according to the following endothermic processes

$CaCO_3 \rightarrow Ca + CO_2 + 1/2\ O_2$ + 808 kJ/mol.

$H_2O \rightarrow H_2 + 1/2\ O_2$ + 286 kJ/mol.

Some of the energy is recovered when the two elements are combined at 480°C by an exothermic process

$Ca + H_2 \rightarrow CaH_2$ - 192 kJ/mol.

The three equations combine to the virtual net reaction

$CaCO_3 + H_2O \rightarrow CaH_2 + CO_2 + O_2$ + 902 kJ/mol.

Similarly, for the production of NaH and LiH from NaCl or LiCl, one obtains

$NaCl + 0.5\ H_2O \rightarrow NaH + Cl + 0.25\ O_2$ +500 kJ/mol

and

$LiCl + 0.5\ H_2O \rightarrow LiH + Cl + 0.25\ O_2$ +460 kJ/mol.

The material is then cooled under hydrogen to room temperature, granulated and packaged in airtight containers.
In use, the hydrides react vigorously with water, and release heat and hydrogen.

$CaH_2 + 2\ H_2O \rightarrow Ca(OH)_2 + 2\ H_2$ - 224 kJ/mol.
$NaH + H_2O \rightarrow NaOH + H_2$ - 85 kJ/mol.
$LiH + H_2O \rightarrow LiOH + H_2$ - 111 kJ/mol.

In fact, the reaction of hydrides with water produces twice the hydrogen contained in the hydride itself, because the water is reduced while the hydride is oxidized to hydroxide. The generated heat has to be removed by cooling and in most cases is lost. For three common hydrides, the energy balances are shown in Table 2.

Table 2. Energy input of alkali metal hydride production

		Ca-Hydride	Na-Hydride	Li-Hydride
Hydride production from		$CaCO_3$	NaCl	LiCl
Energy to make hydride	kJ/mol	902	500	460
H_2 liberated from hydride	mol/mol	2	1	1
Production of H_2	g/mol	4	2	2
Energy input / H_2	kJ/g	225	250	230
=	MJ/kg	225	250	230
HHV of H_2	MJ/kg	142	142	142
Energy input / HHV of H_2	-	1.59	1.76	1.62

The results of this analysis are summarized in Figure 9.

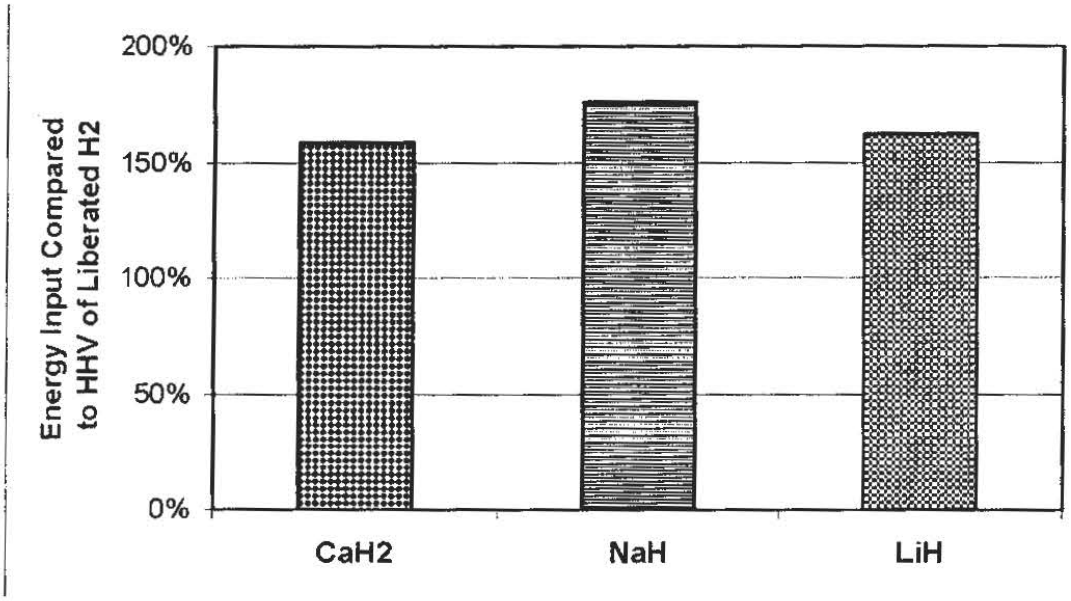

Figure 9. Energy needed to produce alkali metal hydrides relative to the HHV content of the liberated hydrogen

To produce the hydrides, at least 1.6 time more high grade energy has to be invested to produce 1 HHV energy unit of hydrogen, giving a stage efficiency of less than 1/1.6 = 60 %. When the electrolytic production of the alkali metals (calcium, sodium, or lithium) and the efficiency of electric power generation are also considered, the source-to-service energy losses are much higher. They may exceed 500% for electricity from coal-fired power plants. Therefore chemical packaging of hydrogen in alkali metal hydrides would suit very few applications.

The weight of alkali hydride materials appears to pose no problem. One kg of CaH_2 reacting with about 0.86 liter of water yields 96 g of hydrogen, with an HHV energy of 13.6 MJ, while 1 kg LiH yields 36.1 MJ. Alkali metal hydrides are high density energy carriers with energy content comparable to firewood or lignite. However, the energy losses in producing the alkali metals and then the hydrides would discourage their use on any substantial scale.

6. Delivery of Hydrogen

6. 1. Road Delivery of Hydrogen

A hydrogen economy would also involve hydrogen transport by trucks, trains and ships. There are other options for hydrogen distribution, but road transport would always play a role, be it to serve remote locations or to provide back-up supply to filling stations at times of peak demand.

This analysis is based on information obtained from some of the leading providers of industrial gases in Germany and Switzerland: Messer-Griesheim [18], Esso (Schweiz) AG [19], Jani GmbH [20] and Hoyer [21]. The following assumptions are made: Hydrogen gas (at 20 MPa = 200 bar), liquid hydrogen, methanol, ethanol, propane and octane (representing gasoline) are trucked from the refinery or hydrogen plant to the consumer. Trucks with a gross weight of 40 metric tones (30 metric tons for liquid hydrogen) are fitted with suitable tanks or pressure vessels. Also, at full load the trucks consume 40 kg of diesel oil per 100 km. This is equivalent to 1 kg per 100 km per metric ton gross weight. For the return run with emptied tanks, the fuel consumption is reduced accordingly. We assume the same engine efficiency for all trucks.

The 40 metric ton tanker trucks are designed to carry a maximum of fuel. For octane (representing gasoline), ethanol and methanol, the payload is about 26 metric tons. All of it is delivered to the customer.

Compressed gases are normally delivered at a pressure of 20 MPa (200 bar) but the tanks are emptied only to about 4.2 MPa (42 bar) when discharging to a receiver at 4 MPa (40 bar). Such pressure cascades are standard practice today. As a consequence, pressurized gas carriers deliver only 80% of their payload, while 20% of the load remains in the tanks and is returned to the gas plant.

A modern 40 metric ton tube-trailer truck carries 3,000 kg of methane at a pressure of 20 MPa and delivers 2,400 kg to the user. The same truck can carry only 320 kg of hydrogen at a pressure of 20 MPa, and deliver only 288 kg to the customer. Compressors would be required to completely empty the contents of the delivery tank into higher-pressure storage vessels. This would not only make the gas transfer more difficult, but also require additional compression energy, as discussed in Section 5.1 above and Section 7 below. While this might

be economically cost-effective, there would be a high energy cost.

The very low payload of hydrogen gas is due to its low density, as well as the weight of steel cylinders, valves and other equipment necessary for safe handling at a pressure of 20 MPa. However, in anticipation of technical developments, this analysis assumes that in future, trucks will be able to carry 4,000 kg methane or 500 kg of hydrogen, of which 80%, or 3,200 kg and 400 kg respectively, could be delivered to the consumer. Hence a tare weight of 39.6 metric tons would be required to deliver a payload of only 400 kg of gaseous hydrogen – i.e. about 1 per cent. On the return run, the heavy (40 – 0.4 = 39.6 metric tons) empty hydrogen truck consumes proportionally more diesel fuel than the much lighter (40 – 26 = 14 metric tons) empty gasoline carrier.

While in most cases the transport of fuels is weight-limited, for liquid hydrogen it is limited by volume, as shown by the following example. A large trailer-truck may have a useful volume of a box 2.4 m wide, 2.5 m high and 10 m long, i.e. 60 m^3. As the density of the cold liquid is only 70 kg/m3 - or slightly more than that of heavy duty Styrofoam - the box could contain only 4,200 kg of liquid hydrogen. But space is needed for the container, thermal insulation, safety equipment etc. In fact, on a large-size truck, there is room for only about 2,100 kg of the cryogenic liquid. This makes trucking of liquid hydrogen expensive, because despite its small payload, the vehicle has to be financed, maintained, registered, insured, and driven as any truck by an experienced driver. For the analysis we assume the gross weight of the liquid hydrogen carrier is only 30 metric tons.

Today, the fuel economy of modern, clean diesel cars, vans and trucks is excellent, but that of fuel cell vehicles may eventually be slightly better. In both cases, the fuel economy can be improved by hybrid systems, notably due to regenerative braking. Initially, we have not considered any improvements of the fuel economy of either conventional engine or fuel cell vehicles. Thus both fuel converters may have similar tank-to-wheel efficiencies, and hence energy consumption and CO_2 emissions. The consequences may be illustrated as follows: A mid-size filling station on a major freeway might sell 26 metric tons of gasoline each day. This fuel can be delivered by one 40 metric tons gasoline truck. However, it would require 22 tube-trailer hydrogen trucks or nearly three liquid hydrogen trucks to deliver the same amount of energy to the station.

Because of a potentially superior tank-to-wheel efficiency of hydrogen fuel cell vehicles, we now assume that they may need only 70% of the energy required by gasoline or diesel vehicles to travel the same distance. Even so, to fill the same number of vehicles with hydrogen that are nowadays served by a single gasoline truck, it would still take 15 tube-trailer hydrogen trucks. Also, the transfer of pressurized hydrogen from those 15 trucks to the filling station would take much longer than draining gasoline from a single tanker into an underground storage tank, and possibly conflict with established filling station procedures.

Today about one in 100 trucks is a tanker, transporting gasoline or diesel fuel for other road vehicles. Transporting hydrogen by road could require 15 trucks, for a total of 115 – i.e. an increase of some 13%. Hence about one in seven accidents involving trucks could involve a hydrogen truck, and one in forty nine truck to truck collisions could occur between two hydrogen carriers. This scenario is certainly unacceptable for many reasons - particularly in constricted traffic situations like intersections, bridges and tunnels.

For the different fuel options, the energy consumptions for a fuel delivery distance of 100 km are shown in Table 3.

Table 3. Energy consumed for road transport of various fuels and hydrogen

	Units	H_2 Gas	H_2 liquid	Methanol	Ethanol	Propane	Gasoline
Pressure	MPa	20	0.1	0.1	0.1	0.5	0.1
Weight to customer	kg	40,000	30,000	40,000	40,000	40,000	40,000
Weight from customer	kg	39,600	27,900	14,000	14,000	20,000	14,000
Delivered weight	kg	400	2,100	26,000	26,000	20,000	26,000
HHV of delivered fuel	MJ/kg	141.9	141.9	23.3	29.7	50.4	48.1
HHV energy per truck	GJ	57	298	580	771	1007	1252
Relative to gasoline	-	0.045	0.238	0.464	0.616	0.805	1
Diesel consumed	kg	79.6	57.9	54	54	60	54
Diesel HHV energy	GJ	3.56	2.59	2.41	2.41	2.68	2.41
IC engine vehicles:							
Energy consumed to HHV energy delivered	%	6.27	0.87	0.42	0.31	0.27	0.19
Relative to gasoline	-	32.5	4.5	2.2	1.6	1.4	1
No. of trucks for same no. of serviced cars	-	22.0	4.1	2.2	1.6	1.4	1
Fuel cell vehicles:							
H2-efficiency factor	-	0.7	0.7	1	1	1	1
HHV energy delivered	GJ/d	876	876	1252	1252	1252	1252
No. of trucks for same no. of serviced cars	-	15.4	2.9	2.2	1.62	1.24	1

The key results of this analysis for various distances are shown in Figure 10.

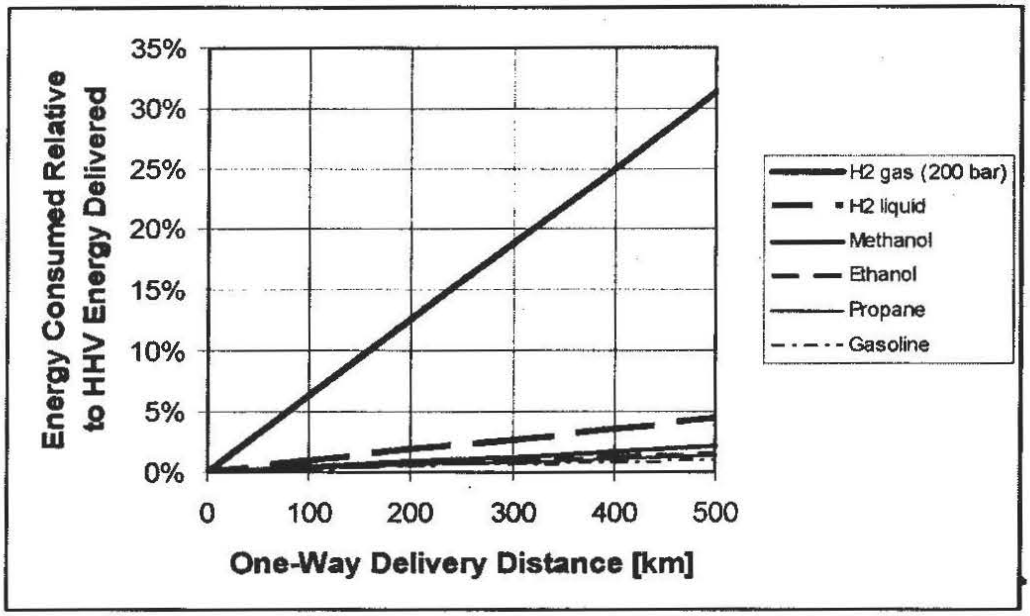

Figure 10. Energy needed for the road delivery of fuels relative to their HHV energy content

The energy needed to transport any of the liquid hydrocarbon fuels is reasonably small. For a one-way delivery distance of 500 km, the diesel fuel consumption remains below 2.5% of the HHV energy content of the delivered fuel. However, for delivering pressurized

hydrogen for fuel cell vehicles, the associated relative energy consumption becomes unacceptable at almost any distance. Compared to road delivery of gasoline, the diesel fuel required to deliver only 70% as much energy as gaseous hydrogen is 32 times, and as liquid hydrogen, about 4.5 times as high.

6. 2. Pipeline Delivery of Hydrogen

Hydrogen pipelines exist today, but they are used to transport a chemical commodity from one production site to another. The energy required to move the gas is of secondary importance, because energy consumption is part of the production process and energy expenditures are one part of the overall production costs. However, this is not so for hydrogen energy transport through pipelines.

The assessment of the energy required to pump hydrogen through pipelines is derived from natural gas pipeline operating experience. For comparison we assume that the same amount of energy is delivered through the same pipeline. In reality, existing pipelines cannot be used for hydrogen, because of diffusion losses, brittleness of materials and seals, incompatibility of compressor lubrication with hydrogen and other technical issues. Also, hydrogen pipelines may have to be larger in diameter to reduce the energy requirement for pumping.

In our analysis, the symbols have the following meaning:

V_o	volumetric flow rate [m^3/s],
A	cross section of pipe [m^2],
v	flow velocity of the gas [m/s],
Δp	pressure drop [Pa],
D	pipeline diameter [m],
L	pipeline length [m]
ρ	density of the gas [kg/m^3],
HHV	higher heating value of the transported gas [MJ/kg],
Re	Reynolds number,
η	dynamic viscosity [kg/(m s)],
ζ	resistance coefficient.

The energy flow through the pipeline, Q [W]

$$Q = V_o \rho HHV = A v \rho HHV. \quad (2)$$

At a pressure of 1 MPa (=10 bar), the densities of methane and hydrogen are 7.2 and 0.9 kg/m^3, respectively. According to equation (2), for the same energy flow through a pipeline of the same diameter, the velocity of hydrogen has to be 3.13 times that of methane.

The Reynolds number is given by:

$$Re = \rho v D / \eta. \quad (3)$$

At a pressure of 1 MPa, the dynamic viscosities of methane and hydrogen are 11.0×10^{-6} and 8.92×10^{-6} kg/(s m), respectively [22]. Hence according to equation (3) and for a pipe diameter of 1 m, the Reynolds numbers of methane and hydrogen are 6.55×10^6 and 3.16×10^6, respectively. Since both values greatly exceed 2,000, the flow regime is turbulent in both cases.

For turbulent flow the theoretical pumping power N [W] requirement is given by:

$$N = V_o \Delta p = A v \Delta p = \pi/4\, D^2 v \Delta p = \pi/4\, D^2 v\, L/D\, 1/2\, \rho v^2 \zeta. \quad (4)$$

From equation (4), the ratio of the theoretical pumping powers NH2 for hydrogen and N_{CH4} for methane, is:

$$N_{H2} / N_{CH4} = (\rho_{H2} / \rho_{CH4}) (v_{H2} / v_{CH4})^3 . \quad (5)$$

Hence, moving a certain energy flow of hydrogen through a given pipeline requires about 3.85 times more energy than for natural gas.

Typically, to transport natural gas through a pipeline at 10 m/s, a compressor is installed every 150 km. They are often fuelled from the gas stream, with each compressor consuming about 0.3% of the local energy flow [23]. Applying this model to the transport of hydrogen through the same pipeline, from equation (5), each compressor would require 0.3 x 3.85 = 1.16 % of the local energy flow. The ratio of the remaining gas mass flow to the original gas mass flow is shown against pipeline length for methane and hydrogen in Figure 11.

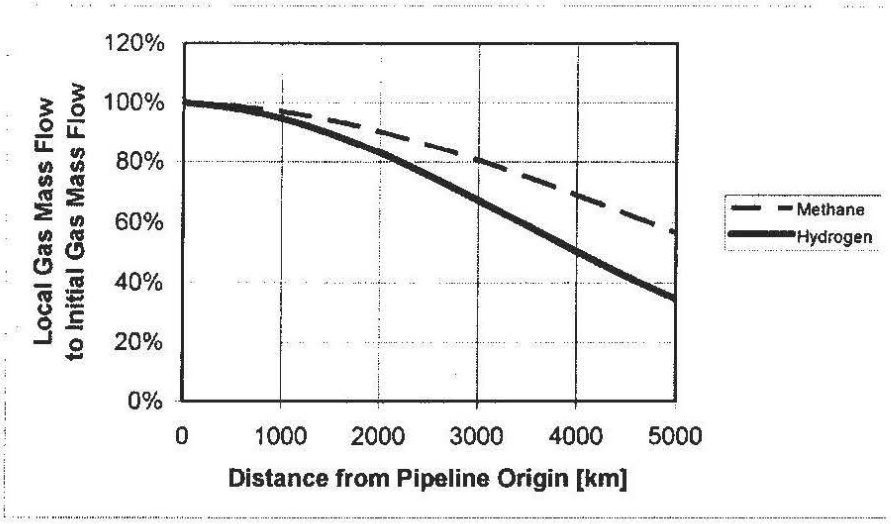

Figure 11. Mass flow remaining in pipeline relative to the mass flow at the pipeline inlet versus pipeline length

For a pipeline length of 3,000 km, the mass fraction consumed for transporting methane (representing natural gas) is about 20%, while that of hydrogen gas is about 34%. This result was obtained for pipes of equal diameter.

In Figure 12, the energy consumed for transport is related to the HHV of the delivered gases. For a transport distance of 3,000 km at least 1.5 units of energy must be invested to deliver 1 unit of hydrogen HHV.

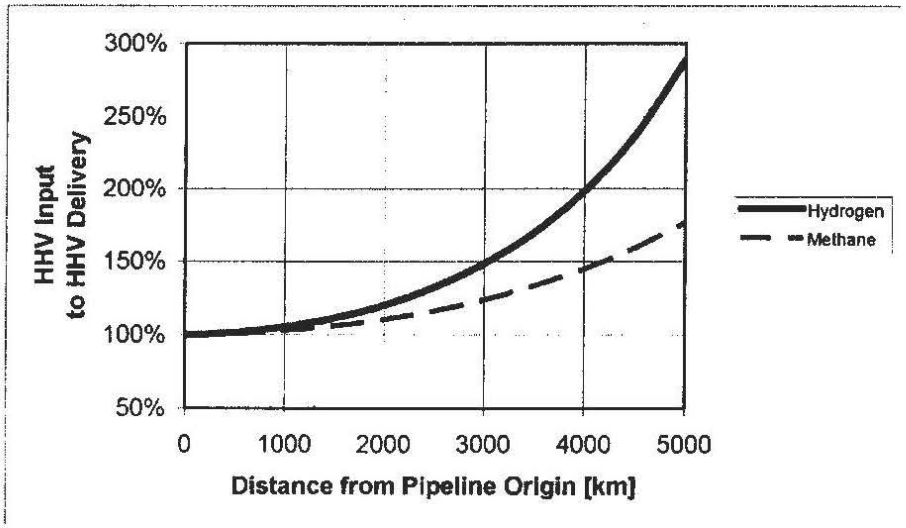

Figure 12. HHV hydrogen energy fed into the pipeline inlet compared to HHV hydrogen energy delivered at the pipeline outlet

Our analysis indicates that, to transport equal energy outflows through the same pipeline, more pumping power is needed for hydrogen than for natural gas. This was derived by projecting existing natural gas experience into a hydrogen future. The final answers must be left to the engineers responsible for design and optimization of any such hydrogen pipeline systems.

Moreover, although often ignored, leakage of methane from pipelines is finite. Indeed, it is a matter of concern when transporting natural gas over long distances, as from Russia to Europe. However, due to its much smaller molecule, leakage of hydrogen would be far greater. Unless it was very tightly controlled, this factor could by itself completely destroy the energetic and economic case for long hydrogen pipelines.

6. 3. On-site Generation of Hydrogen

One option for providing hydrogen at filling stations and dispersed depots is on-site generation of the gas by electrolysis. Again, the energy needed to generate and compress hydrogen by this scheme is compared to the HHV energy content of the hydrogen delivered to local customers. Natural gas reforming is not considered for the reasons stated in Section 4.2. The analysis is done for filling stations serving 100 and 2,000 conventional cars and trucks per day. On average, each vehicle is assumed to take 60 liters (= 50 kg) of gasoline or diesel oil. For 100 and 2,000 vehicles per day, the energy equivalents would be about 1,700 and 34,000 kg of hydrogen per day, respectively. The comparison is based on the same transportation services for IC engine and fuel cell vehicles. However, as stated in Section 6.1, compared with IC engine vehicles, those with fuel cells may have a higher tank-to-wheel efficiency, and so consume less energy per unit distance. Based on the HHV of both gasoline and hydrogen, we assume that fuel cell vehicles need only 70% as much energy.

The comparison is based on the same transportation services for fossil fuel and hydrogen vehicles. Because of their reduced range, hydrogen vehicles would require more fill-ups to receive the same energy equivalent of 60 liters of gasoline. The electrolyzer efficiency varies with size from 70 to 80% for 100 and 2,000 vehicles per day, respectively. Also, losses occur in the AC-DC power conversion. Making hydrogen by electrolysis would require average continuous electric powers of 3 and 51 MW respectively. Additional power would be needed for the water make-up (0.09 and 1.52 MW), and for compressing the hydrogen to 10 MPa for on-site storage and 40 MPa for rapid transfer to vehicle tanks at 35 MPa (0.29 and 4.45 MW). In all, to generate and store hydrogen for 100 and 2,000 vehicles per day, the filling station must be supplied with continuous electric power of 3 and 57 MW. Also 11 and 214 m^3 of water would be consumed daily. The larger value corresponds to about 2.5 liters per second.

For on-site hydrogen production plants, operating continuously and serving various numbers of vehicles per day, the key assumptions and the most important results are presented in Table 4.

Table 4. Assumptions and results for on-site hydrogen production

	l/d	100	500	1000	1500	2000
Gasoline, Diesel / vehicle	kg	50	50	50	50	50
Fossil energy supplied	GJ/d	241	1,203	2,407	3,610	4,814
FC vehicle efficiency factor	%	70	70	70	70	70
Hydrogen energy supplied	GJ/d	176	878	1,755	2,633	3,510
Hydrogen mass supplied	kg/d	1,188	5,938	11,877	17,815	23,753
Electrolyzer efficiency	%	70	75	78	79	80
AC/DC conversion efficiency	%	93	94	95	96	96
Energy for electrolysis	GJ/d	259	1,195	2,274	3,332	4,388
Water needed	m^3/d	11	53	107	160	214
Energy for water supply	GJ/d	8	36	68	100	132
H_2-compression, 20, 40 MPa	GJ/d	35	151	282	408	531
Total energy needed	GJ/d	301	1,381	2,624	3,840	5,051
Continuous power needed	MW	3	16	30	44	58
Energy wasted per H_2 HHV	%	79	64	56	52	50
Relative to supplied H_2 HHV	%	179	164	156	152	150

The final results of this analysis are shown in Figure 13.

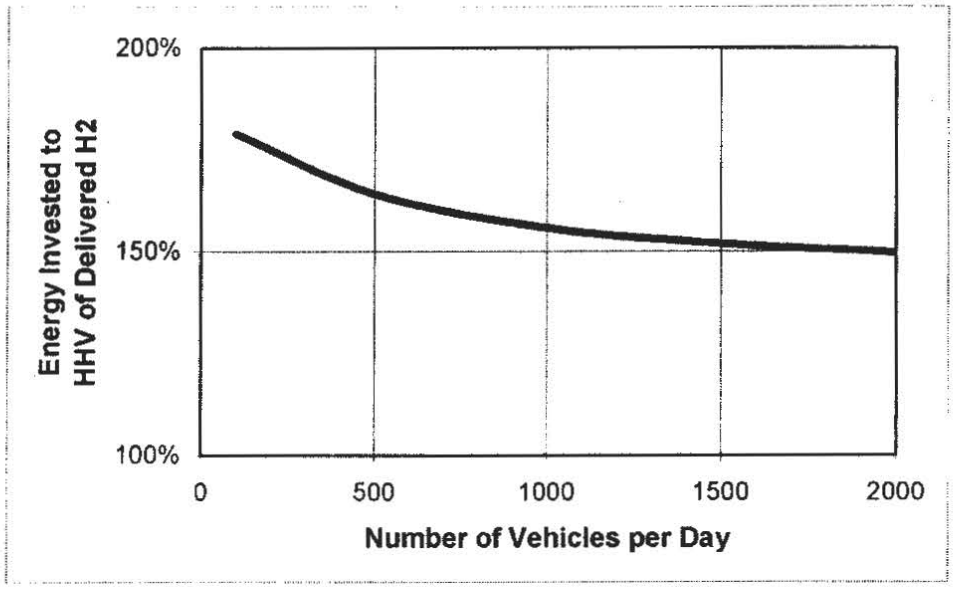

Figure 13. Energy needed for on-site generation of hydrogen by electrolysis stored at 10 MPa and subsequent compression to 40 MPa for rapid ransfer to 35 MPa vehicle tanks relative to the HHV energy content the hydrogen

Hence for 1,000 vehicles per day, about 1.65 units of energy must be invested to obtain 1 unit of hydrogen HHV, giving a stage efficiency of 60%. If the electricity was generated by coal-fired power plants, the overall well-to-tank efficiency could be less than 20%.

Assuming continuous operation, every twenty to thirty hydrogen filling stations on well-frequented highways would consume the output of a 1 GW electric power plant. The availability of such large amounts of electricity may certainly be questioned. Today, about one sixth of the national total of energy consumed is electricity. The substitution of the present supply of gasoline and diesel fuel with hydrogen generated by electrolysis at filling stations would require a 3 to 5 fold increase of the national electric power generating capacity, and the energy to run them continuously. If this power were derived from coal, changing to

such "zero emission vehicles" would lead to a considerable increase of CO_2 emissions. Hence, it would be better to develop energy-efficient vehicle technologies that do not use elemental hydrogen (see below).

7. Transfer of Hydrogen

Liquids can be drained from a full into an empty container by the action of gravity. No additional energy is required, unless the liquid is transferred from a lower to a higher elevation, or at accelerated flow rates.

However, the transfer of pressurized gases obeys other laws. Assume two tanks of equal volume, one full at 20 MPa and the other empty at 0 Pa gauge pressure. After opening the valve between the vessels, gas will flow into the empty tank, but the flow will cease when the pressures approach equilibrium. Two tanks of equal size are then half full or half empty. Moreover, the transfer process is complicated by temperature effects. With the rapid pressure drop, the contents of the supply tank are cooled, due to the Joule-Thompson effect. Hence at equal pressures, the density of the remaining gas is higher than that of the transferred gas in the other tank. As a consequence, more mass remains in the supply tank than is transferred into the receiving tank. Equal mass transfer is accomplished only after some time, when the temperatures have reached equilibrium again. For tanks of similar size, this is illustrated in Figure 14.

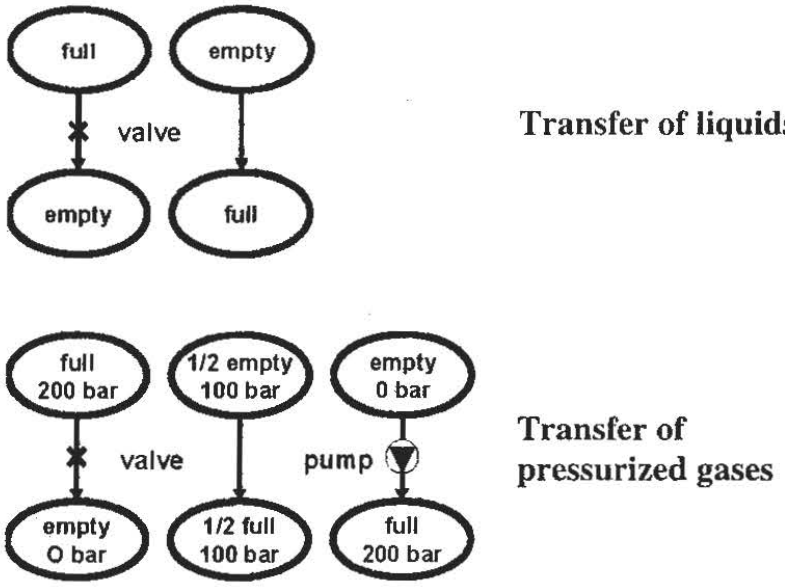

Figure 14. Schematic representation of the transfer of liquids and gases

To fill a small tank from a high pressure vessel of substantial size would take no additional energy. Unfortunately, automotive applications require large stationary supply containers, which cannot be subjected to high internal pressures, and small high pressure tanks in the vehicles to maximize the driving range. Consequently, pumping would be required to transfer hydrogen from the supply tank into the vehicle tank. The amount of energy required for the gas transfer by pumping is given by the difference of the work needed to compress the gas to final pressure p_2 (e.g. 40 MPa) and work needed to reach the intermediate pressure p_1 of the large volume storage (e.g. 10 MPa). For a multistage compression, the compression work is about twice the ideal isothermal compression (see Section 5.1), i.e.

$$W \approx 2\, p_0 V_0 [\ln (p_2/p_0) - \ln (p_1/p_0)] \quad (6)$$

With:			
	W	[J/kg]	specific compression work,
	p_0	[Pa]	initial pressure,
	p_1	[Pa]	intermediate pressure,
	p_2	[Pa]	final pressure,
	V_0	[m^3/kg]	initial specific volume.

For the example case

p_0	= 10 MPa	(= 1 bar),
p_1	= 10 MPa	(= 100 bar),
p_2	= 40 MPa	(= 400 bar),
V_0	= 11.11 m^3/kg,	
p_0V_0	= 1.111 MJ/kg.	

To transfer the remaining hydrogen from the supply tank into the receiving tank by a multistage compression, the energy required is:

$$W = 1.54 \text{ MJ/kg}.$$

This is about 1.1% of the HHV energy content of the compressed hydrogen. Including mechanical and electrical losses of the small compressors installed at the filling stations, this number would be closer to 3%. Moreover, to transfer hydrogen from a large storage tank at 10 MPa into a small vehicle tank at 35 MPa, would require at least 4.32 MJ/kg or, including other losses, at least 3% of the HHV energy content of the transferred hydrogen. Hence, to transfer 1 unit of HHV hydrogen energy from a 10 MPa storage tank to a 35 MPa vehicle tank would require at least 1.03 units of (electrical) energy.
At least 1.08 electrical energy units must be invested to transfer 1 HHV hydrogen energy unit from a 10 MPa storage vessel to a 70 MPa storage tank onboard of a hydrogen vehicle. With other losses this would become 1.12 units.

8. Summary of Results

As far as we could determine, the upstream energy needed to operate a hydrogen economy has not previously been fully assessed. Hence, the intent of this compilation is to create an awareness of the fundamental weaknesses of an elemental hydrogen economy. However, the energy cost of producing, packaging, distributing, storing and transferring hydrogen may have been analyzed elsewhere in other contexts. If so, the findings of such studies may be used to confirm or correct our results. Furthermore, readers of this study are invited to refine and extend the analysis.

Meanwhile, we find that the conversion of natural gas into hydrogen cannot be the solution of the future. Hydrogen produced by reforming natural gas may cost less (in both money and energy) than hydrogen obtained by electrolysis, but for most applications, natural gas is as good as, if not better than hydrogen. For use in road transport, if natural gas were converted to hydrogen, the well-to-wheel efficiency would be reduced and hence, for given final energy demand, the emission of CO_2 would be increased. Moreover, for all stationary applications, the distribution of energy as electricity would be energetically superior to the use of hydrogen as energy carrier.

For the use of electrolytic hydrogen in road transport, the results are presented in Table

5, where the four possible supply pathways are:

A produced by electrolysis, compressed to 20 MPa and distributed by road to filling stations or consumers, stored at 10 MPa, then compressed to 40 MPa for rapid transfer to vehicles at 35 MPa.

B produced by electrolysis, liquefied and distributed by road to filling stations or consumers, then transferred to vehicles .

C produced by electrolysis on-site at filling stations or consumers, stored at 10 MPa, then compressed to 40 MPa for rapid transfer to vehicles at 35 MPa.

D produced by electrolysis and used to make alkali metal hydrides.

Table 5. Energy consumption for different hydrogen delivery paths

	Energy cost in HHV of H_2	Factor	Path A gas	Path B liquid	Path C onsite	Path D hydride
Production of H_2						
Electrolysis	43%	1.43	1.43	1.43		1.22*
Onsite production	65%	1.65			1.65	
Packaging						
Compression 20 MPa	8%	1.08	1.08			
Liquefaction	40%	1.40		1.40		
Chemical hydrides	60%	1.60				1.60
Distribution						
Road, 20 MPa H_2, 100 km	6%	1.06	1.06			
Road, liquid H_2, 100 km	1%	1.01		1.01		
Storage						
Liquid H_2, 10 days	guess: 5%	1.05		1.05		
Transfer						
10 MPa to 40 MPa	3%	1.03	1.03		1.03	
Delivered to User						
Energy Input/HHV of H_2			1.69	2.12	1.69	1.95**

* Only 50% of the hydrogen released comes from electrolysis

** Excluding energy needed to produce alkali metals

Even assuming ideal processes and current industrial practice, the analysis reveals that considerable amounts of energy are lost between the electrical source energy and the hydrogen energy delivered to the consumer. For road delivery of compressed hydrogen, Path A, the electrical energy input exceeds the HHV energy of the delivered hydrogen by a factor of at least 1.69. In the case of liquid hydrogen, Path B, the factor is at least 2.12. For on-site hydrogen production, Path C, the factor is at least 1.69. For delivery of hydrogen by chemical hydrides, Path D, the factor is at least 1.95. It is unlikely that any of these would be attractive. Hence elemental hydrogen may provide practical solutions in some niche markets, but it cannot become important in a future energy economy.

Today, the losses between oil wells and filling stations for transportation, refining and distribution, are about 12%. Thus the well-to-tank efficiency of gasoline is about 88 per cent, and is slightly higher for diesel fuel. As shown above, in an elemental hydrogen economy,

depending on the path chosen and even assuming many ideal processes, the upstream losses would be much higher, at 69% to over 100%. Hence even in the best attainable case, the well-to-tank efficiency on an HHV basis cannot be much above 50%.

8. 1. The Limitations of a Elemental Hydrogen Economy

Even for the best pathways, A and C, the elemental "Hydrogen- Economy" depicted in Figure 15. is not convincing.

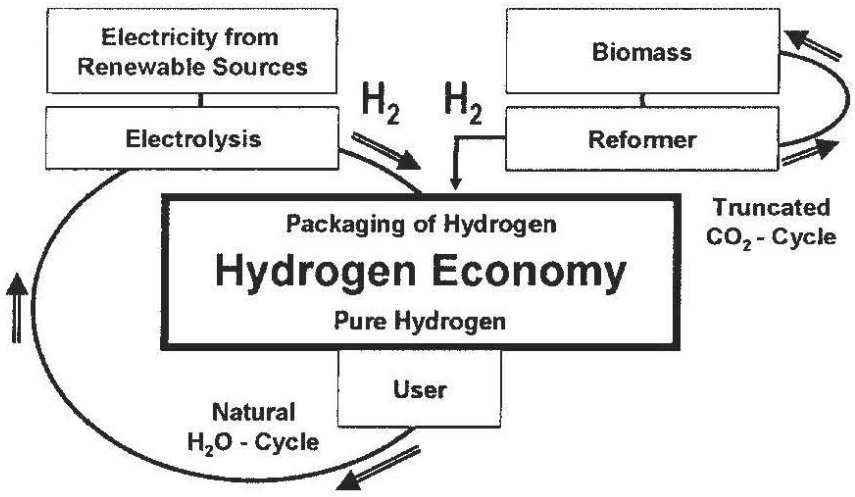

Figure 15. Elemental Hydrogen Economy based on the natural cycle of water.Elemental hydrogen is provided to the user

All the losses with the elemental Hydrogen Economy are directly related to the nature of hydrogen. Hence they cannot be significantly reduced by any amount of research and development. We have to accept that hydrogen is the lightest element and its physical properties do not suit the requirements of the energy market. The production, packaging, storage, transfer and delivery of the gas are so energy consuming that other solutions must be considered. Mankind cannot afford to waste energy for uncertain benefits; the market economy will always seek practical solutions and, as energy becomes more expensive, select the most energy-efficient. Judged by this criterion, the elemental "Hydrogen-Economy" can never become a reality.

This study provides some clues for the strengths and weaknesses of hydrogen as an energy carrier. Certainly the proportion of energy lost depends on the application. The analysis shows that transporting hydrogen gas by pipeline over thousands of kilometers would suffer large energy losses. Moreover, in practice, the demands on materials and maintenance would probably result in prohibitive levels of leakage and system costs. Furthermore, the analysis shows that compression or liquefaction of the hydrogen, and transport by trucks would incur large energy losses. However, hydrogen solutions may be viable for certain niche applications. For example, excess rooftop solar electricity could be used to generate hydrogen, stored at low pressure in stationary tanks, for heat and power co-generation with engines or fuel cells may be a viable solution for private buildings.

As stated at the beginning, hydrogen generated by electrolysis may be the best link between - mostly physical - energy from renewable sources and chemical energy. It is also the ideal fuel for modern clean energy conversion devices like portable fuel cells, and can even be used in modified IC engines. But hydrogen is far from ideal for carrying energy from primary sources to distant or mobile end users. For the commercial bridge between the electrolyzer and the fuel cell or IC engine, other solutions must be considered.

8. 2. A Synthetic Liquid Hydrocarbon Economy

The hydrogen-only perspective is obscuring a superior clean energy solution - an energy economy based on synthetic liquid hydrocarbons. The ideal energy carrier would be a liquid with a boiling point above 80°C and a freezing point below -40°C. Such energy carriers would remain liquid under normal climate conditions and at high altitudes. Gasoline, diesel fuel (= heating oil) are excellent examples. They are in common use not only because they can be derived from crude oil and natural gas, but mainly because their physical properties make them ideal for transportation applications. They emerged as the best solutions with respect to handling, storage, transport and energetic use. Even if oil had never been discovered, the world would not use synthetic hydrogen, but one or more synthetic hydrocarbons for portable fuels, and particularly for road transport.

A Synthetic Liquid Hydrocarbon Economy could be based on the two natural cycles of water and carbon dioxide, and provide consumer-friendly energy carriers produced entirely from renewable sources. Water is the source of hydrogen while carbon is taken from the biosphere ("bio-carbon") - e.g. from biomass, organic waste and CO_2 captured from flue gases. Typically, biomass has a hydrogen-to-carbon ratio of two. In methanol synthesis, two additional hydrogen atoms are attached to every bio-carbon. Instead of converting biomass into hydrogen, hydrogen from renewable sources or even from water could be added to biomass by a chemical process to form methanol or ethanol. In a Synthetic Liquid Hydrocarbon Economy, carbon atoms stay bound in the energy carrier until its final use. They are then returned to the atmosphere (or in stationary plant - may be directly recycled by recovery from flue gases). Due to the lesser upstream energy required - especially for packaging, delivery, storage, and transfer - such Synthetic Liquid Hydrocarbons are environmentally superior to elemental hydrogen itself.

A schematic of a "Synthetic Liquid Hydrocarbon Economy" is shown in Figure 16.

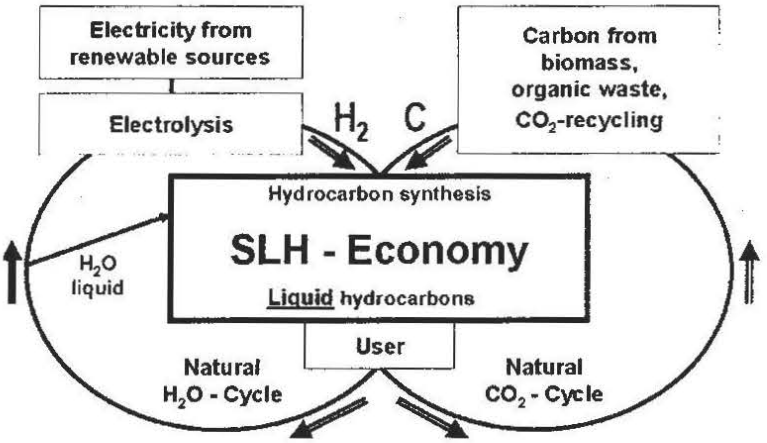

Figure 16. A Synthetic Liquid Hydrocarbon Economy may be based on the two natural cycles of water and carbon dioxide. Natural and synthetic liquid hydrocarbons are provided to the user

8. 3. Liquid Hydrocarbons

Any synthetic liquid fuel must satisfy a number of requirements. It should be liquid under normal pressure at temperatures between -40°C and 80°C, easy to synthesize, nontoxic, and suitable for use in IC engines, fuel cells, and boilers. Many hydrocarbons may be synthesized from hydrogen and carbon. Some compounds satisfying the liquidity criterion are tabulated below. However, considerations of manufacturing, safety, combustion etc., may eliminate some from or add new options to the list.

The following liquid hydrocarbons are considered:

A	Ammonia	NH_3.	
B	Octane	C_8H_{18}	or $CH_3(CH_2)_6CH_3$.
C	Toluene (Methylbenzene)	C_7H_8	or $C_6H_5CH_3$.
D	Ethylbenzene	C_8H_{10}	or $C_6H_5CH_2CH_3$.
E	Isopentane (2-Methylbutane)	C_5H_{12}	or $CH_3CH(CH_3)CH_2CH_3$.
F	Isobutane (2-Methylpropane)	C_4H_{10}	or $CH_3CH(CH_3)CH_3$.
G	Ethylmethylether (EME)	C_3H_8O	or $CH_3OC_2H_5$
H	Dimethlyether (DME)	C_2H_6O	or CH_3OCH_3,
I	Methanol	CH_4O	or CH_3OH,
J	Ethanol	C_2H_6O	or CH_3CH_2OH,
K	Hydrogen (for comparison)	H_2.	

The characteristic data of these substances are shown in Table 6.

Table 6. Physical and energetic properties of selected hydrocarbons [3]

Fuel		Mol. Weight	Density (25°C)	H_2-Content	H_2-Density	HHV	Energy per Volume
		mole	kg/m³	weight-%	kgH_2/m^3	MJ/kg	GJ/m³
A	Ammonia	17.0	771	17.6	136	22.5	17.35
B	Octane	114.2	698	15.8	110	47.9	33.43
C	Toluene	92.2	862	8.7	75	42.5	36.60
D	Ethylbenzene	106.2	863	9.4	81	43.0	37.10
E	Isopentane	72.1	615	16.6	102	48.6	29.89
F	Isobutane	58,1	551	13.3	95	49.4	27.20
G	EME	60.1	725	16.6	97	35.1	25.43
H	DME	46.1.	669	13.0	87	31.7	21.19
I	Ethanol	46.1	785	13.0	102	29.7	23.28
J	Methanol	32,0	787	12.5	98	22.7	17.86
K	L. Hydrogen	2.0	70	100.0	70	141.9	9.93

The key properties of the tabulated substances are shown in Figure 17.

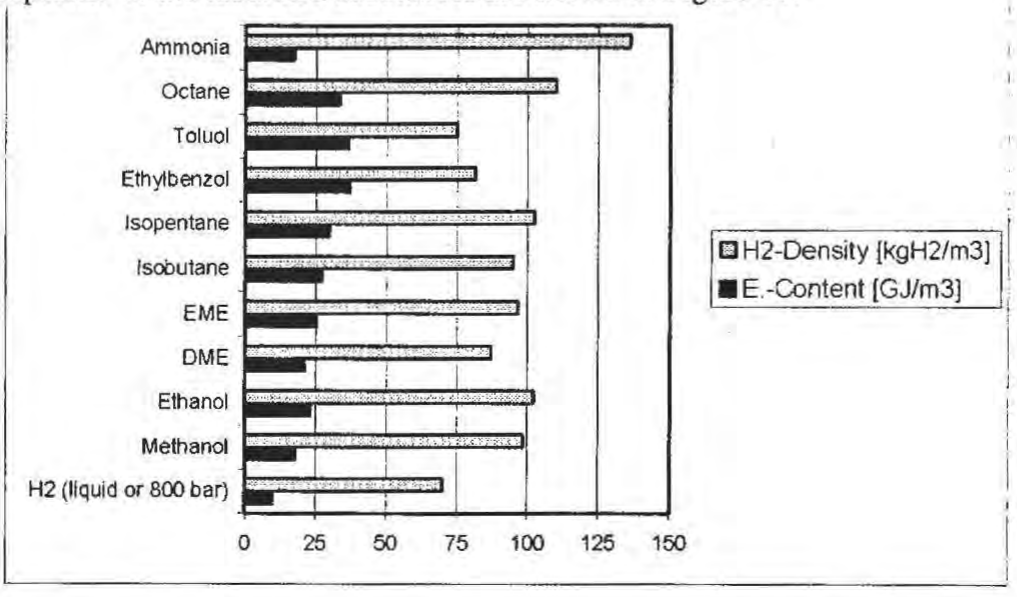

Figure 17. Hydrogen density and HHV energy content of ammonia and selected synthetic liquid hydrocarbon fuels

Compared with liquid or high-pressure (80 MPa) gaseous hydrogen, each of the ten compounds (A to J) contains from two to almost four times as much energy per unit volume. Of these, ammonia, methanol, ethanol, DME, and toluene have relatively simple molecular structures, while the gasoline-like octane is the best hydrogen carrier and also second with respect to energy content per unit volume.

Although ammonia contains 136 kg of hydrogen per cubic meter, it is extremely poisonous. Whether one wants to distribute energy or hydrogen, the best way is to combine it with carbon to make a liquid fuel. Compared with methanol and ethanol, octane is harder to synthesize, e.g. by the Fischer-Tropsch process, and harder to reform to produce hydrogen for use in fuel cells. Dimethylether (DME) has good characteristics, but is less versatile than the alcohols.

Methanol can be directly converted to electricity either via heat engines or by Direct Methanol Fuel Cells (DMFC), Molten Carbonate Fuel Cells (MCFC) and Solid Oxide Fuel Cells (SOFC). It can also be reformed easily to hydrogen for use in Polymer Electrolyte Fuel Cells (PEFC or PEM) and Alkaline Fuel Cells (AFC). Methanol could become a universal fuel for fuel cells and many other applications.

Ethanol is non-poisonous (in moderation), and may be derived directly from biomass, e.g. by fermentation, as well as synthesized from bio-carbon and water. Having a relatively high volumetric energy density, it is particularly suitable for use in vehicles. It may be used in spark ignition ("SI") engines as an 85% blend with gasoline (E85) in dedicated or Flexible Fuel Vehicles, or in compression ignition ("CI") engines as a 95% blend with diesel fuel (E95) [24]. In principle, it could also be used in fuel cell vehicles. Hence ethanol could be an excellent solution for an energy economy based on renewable energy sources and the recycling of carbon dioxide.

9. Conclusions

The analysis shows that an elemental "Hydrogen Economy" for road transport would have a low well-to-tank efficiency and hence a low environmental quality. In particular, if the electrical energy were generated in coal-fired power plants, the well-to-tank efficiency might fall below 20%. Even if the hydrogen were used in fuel cells, the overall energy efficiency would be comparable to that of steam engines in the early half of the 20th century, while the CO2 emissions would have significantly increased due to the growth of overall energy consumption.

The time has come to shift the focus of energy strategy planning, research and development from an elemental „Hydrogen Economy" to a „Synthetic Liquid Hydrocarbon Economy". This means directing the limited human, material, and financial resources to providing technical solutions for a sustainable energy future built on the two closed clean natural cycles of water (for hydrogen) and CO2 (for carbon). Fortunately, much of the technology exists already – e.g. for growing biomass, and for fermentation and distillation to produce ethanol. Both methanol and ethanol could be synthesized from water and carbon. Provided that the carbon is taken not from fossil resources ("geo-carbon"), but from the biosphere or recycled from power plants ("bio-carbon"), the "Synthetic Liquid Hydrocarbon Economy" would be far superior to an elemental "Hydrogen Economy", both energetically and environmentally.

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